Community Solar Project Interconnection

Community Solar Project System Impact Study Report

Completed for

(“Applicant”)
OCS001

Proposed Point of Interconnection

Circuit 5D69 out of Prineville substation near 44°17’4.24”N, 120°53’18.28”W

May 13, 2020

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1.0 Description of the Community Solar Project

("Applicant") proposed interconnecting 1.46 MW of new generation to PacifiCorp's ("Public Utility") circuit 5D69 out of Prineville substation located in Crook County, Oregon. The project ("Project") will consist of twelve (12) Sungrow 125HV 125 kW inverters for a total requested output of 1.46 MW (as measured at the Point of Interconnection, 1.5 MW nameplate). The requested commercial operation date is November 1, 2020.

The Public Utility has assigned the Project "OCS001."

2.0 Approval Criteria for Tier 4 Interconnection Review

Pursuant to the Section I(1) of the Public Utility's CSP Interconnection Procedures, a Public Utility must use the Tier 4 review procedures for an application to interconnect a Community Solar Project that meets the following requirements:

(a) The Community Solar Project does not qualify for or failed to meet Tier 2 review requirements; and

(b) The Community Solar Project must have a nameplate capacity of three (3) megawatts or less.

3.0 Scope of the Study

Pursuant to Section I(6)(g) of the CPS Interconnection Procedures, the System Impact Study Report shall consist of: (1) the underlying assumptions of the study; (2) a short circuit analysis; (2) a stability analysis; (3) a power flow analysis; (4) voltage drop and flicker studies; (5) protection and set point coordination studies; (6) grounding reviews; (7) the results of the analyses; and (8) any potential impediments to providing the requested Interconnection Service, including a non-binding informational network resource interconnection service (NRIS) assessment in Appendix 2. In addition, the System Impact Study shall provide a list of facilities that are required as a result of the Community Solar Project request and non-binding good faith estimates of cost responsibility and time to construct.

4.0 Proposed Point of Interconnection

The Applicant's proposed Community Solar Project is to be interconnected to the Public Utility's distribution circuit 5D69 out of Prineville substation via a new 12.5 kV overhead primary meter. The Point of Interconnection ("POI") will be near existing pole mapstring 1415015.0, facility point 119901 at approximately 44°17'4.24"N, 120°53'18.28"W. Figures 1 and 2 below are a map and one-line diagram that specifies the location and illustrates the interconnection of the proposed generating facility to the Public Utility's system.

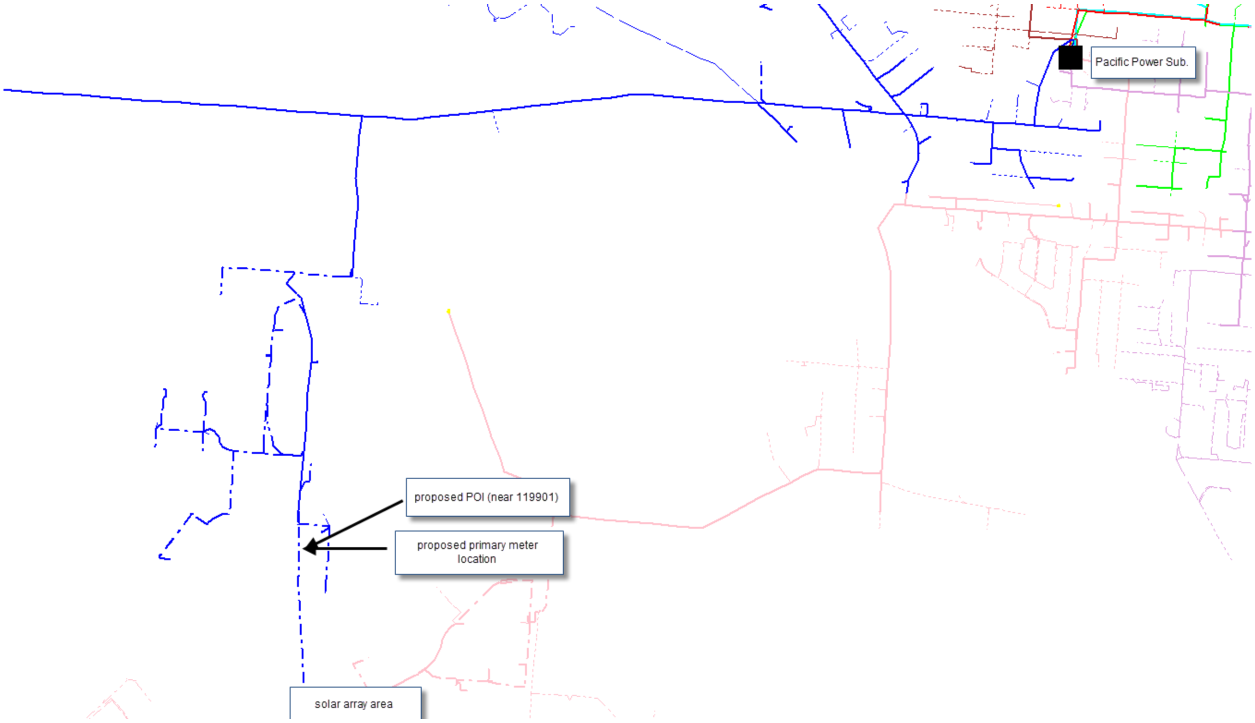

Figure 1: System Map

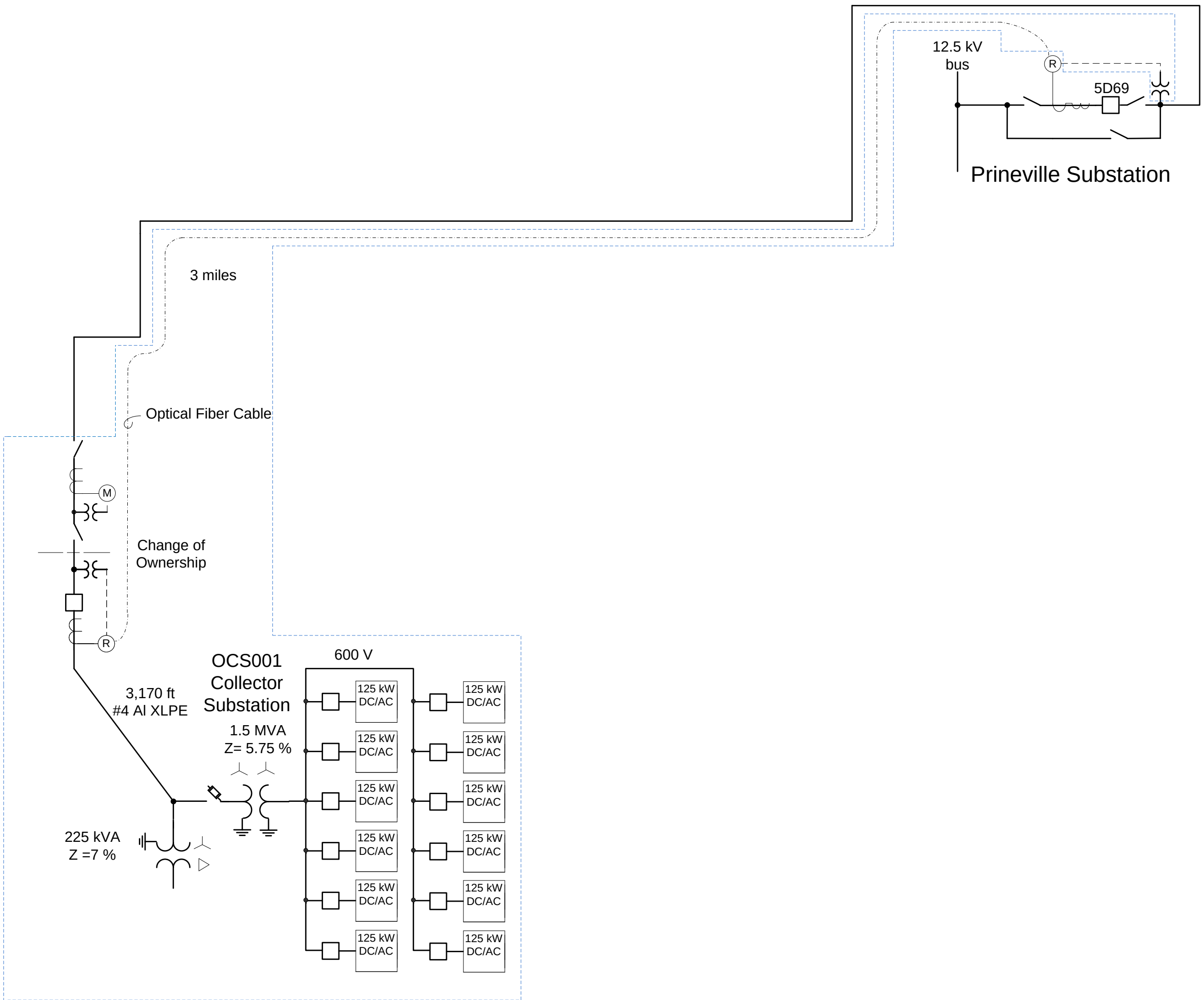

Figure 2: System One Line Diagram

5.0 Study Assumptions

- All active higher-priority requests for transmission service and/or generator interconnection service (including requests in the traditional interconnection queue and other requests in the Community Solar queue) in the local area of the requested point of interconnection will be considered in this study and are listed in Appendix 1. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.
- The Applicant's request for interconnection service in and of itself does not convey transmission service.
- This study assumes the Project will be integrated into Public Utility's system at the agreed upon and/or proposed Point of Interconnection ("POI").
- The Applicant will construct and own any facilities required between the Point of Interconnection and the Project unless specifically identified by the Public Utility.
- Line reconductor or fiber underbuild required on existing poles will be assumed to follow the

most direct path on the Public Utility's system. If during detailed design the path must be modified it may result in additional cost and timing delays for the Applicant's project.

- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum Western Electricity Coordinating Council ("WECC"), North American Electric Reliability Corporation ("NERC"), and Public Utility performance and design standards.
- Interconnection Request Q0850 and all related upgrades are assumed to be complete by December 2020. Should this Interconnection Request be withdrawn it will result in additional requirements for the Interconnection Customer's Interconnection Request.
- This report is based on information available at the time of the study. It is the Applicant's responsibility to check the Public Utility's web site regularly for transmission system updates (https://www.oasis.oati.com/ppw)

6.0 REQUIREMENTS

6.1 COMMUNITY SOLAR PROJECT MODIFICATIONS

The Community Solar Project and Interconnection Equipment owned by the Applicant are required to operate under automatic voltage control with the voltage sensed electrically at the Point of Interconnection. The Community Solar Project should have sufficient reactive capacity to enable the delivery of 100 percent of the plant output to the Point of Interconnection at 0.8 power factor (absorbing VARs) measured at steady state conditions.

Generators capable of operating under voltage control with a voltage droop are required to do so. Studies will be required to coordinate the voltage droop setting with other facilities in the area. In general, the Community Solar Project and Interconnection Equipment should be operated so as to maintain the voltage at the Point of Interconnection between 1.01 pu to 1.045 pu. At the Public Utility's discretion, these values might be adjusted depending on the operating conditions. Within this voltage range, the Community Solar Project should operate so as to minimize the reactive interchange between the Community Solar Project and the Public Utility's system (delivery of power at the Point of Interconnection at approximately unity power factor). The voltage control settings of the Community Solar Project must be coordinated with the Public Utility prior to energization (or interconnection). The reactive compensation must be designed such that the discreet switching of the reactive device (if required by the Applicant) does not cause step voltage changes greater than +/-3% on the Public Utility's system.

All generators must meet applicable WECC low voltage ride-through requirements as specified in the interconnection agreement.

As per NERC standard VAR-001-1, the Public Utility is required to specify voltage or reactive power schedule at the Point of interconnection. Under normal conditions, the Public Utility's system should not supply reactive power to the Community Solar Project.

The Applicant will be required to install a transformer that will hold the phase to neutral voltages within limits when the generation facility is isolated with the Public Utility's local system until the generation disconnects. The proposed wye – wye step-up transformer will not accomplish the stabilization of the phase to neutral voltages on the 12.5 kV system. The circuit that the project is connecting to is a four wire multi-grounded circuit with line to neutral connected load. Figure 2 shows the addition of a wye – delta grounding transformer of adequate power size and impedance that will meet the requirement.

6.2 Distribution/Transmission Line Modifications

Public Utility will install a new riser pole and extend 1/0 underground conductor south (100-200 feet) to a primary meter vault. The Applicant will interconnect with Public Utility at this primary meter vault. The riser pole will be fused with 80T line fuses.

To maintain fuse coordination the upstream 65T line fuses at pole 01415015.0-029862 will be replaced with solid blades and fault indicators.

6.3 Existing Breaker Modifications – Short-Circuit

The increase in the fault duty on the system as the result of the addition of the generation facility with photovoltaic arrays fed through 12 – 125 kW inverters connected to a 1.5 MVA 12.5 kV – 600 V transformer with 5.75% impedance will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

6.4 Protection Requirements

The OCS001 generating facility will need to disconnect from the network in a high speed manner for faults on the 12.5 kV line on circuit 5D69 out of Prineville substation. The minimum daytime load on circuit 5D69 is below the maximum potential power output of the proposed OCS001 generating facility. For this reason the imbalance condition of the load and generation cannot be relied upon to cause the high speed disconnection of the generating facilities for faults on the distribution system. A transfer trip circuit will need to be installed between Prineville substation and the Applicant's circuit recloser at the POI. Since most faults on overhead lines are temporary and the circuit can be restored as soon as all the sources of power to the fault have been disconnected the breaker 5D69 at Prineville substation is equipped with automatic reclosing. When breaker 5D69 opens the transfer trip signal will be sent to the circuit recloser. An optical fiber cable will need to be installed between Prineville substation and the circuit recloser. The transfer trip signal will be sent over the optical fiber cable.

To ensure that the automatic reclosing of breaker 5D69 does not take place before the generating facility plant disconnects, a dead line checking control circuit will be installed. The dead line checking control circuit will delay the reclosing until the line is no longer energized to ensure that no damage is done to any of the existing customers' equipment. The enabling of these controls will require the addition of a voltage instrument transformer on the line side of breaker 5D69. As part of the Q0850 interconnection request the feeder relay at Prineville substation for 5D69 will be replaced. The relay that will be installed will have the capacity to communicate with the circuit recloser at the POI and monitor the voltage on the line side for the breaker to supervise the automatic reclosing. The relay equipment currently installed at Prineville substation does not have these capabilities. It is assumed for this study that the Q0850 project has upgraded the relay at Prineville substation.

A 12.5 kV circuit recloser will need to be installed at the POI for the OCS001 project. The circuit recloser will need to be equipped with a Schweitzer Engineering Laboratories ("SEL") 651R relay/controller and voltage instrument transformers mounted on the Public Utility side of the circuit recloser. The 651R will perform the following protection functions:

1. Detect faults on the 12.5 kV tie line to the generating facility
2. Detect faults on the 12.5 kV line to Prineville substation
3. Monitor the voltage and react to under or over frequency, and /or magnitude of the voltage
4. Monitor the unbalance current flowing from the generating facility to the detect excessive current flow that could damage the grounding transformer
5. Receive transfer trip from Prineville substation

6.5 Communication Requirements

The Public Utility will install approximately 3 miles of ADSS fiber optic cable on the distribution line between Prineville substation and the Applicant's recloser. Patch panels will be installed at both ends and FO jumpers from the patch panels to the relays' FO transceivers

6.6 Substation Requirements

At the Prineville substation, the following has been identified as required and may change during the detailed design:

1- 12.5kV voltage transformer

6.7 Metering Requirements

Interchange Metering

The Public Utility metering shall be installed at the point of delivery adjacent to the Applicants transformer and disconnect devices. The metering instrument transformers will be installed inside a primary metering station, with the meter socket located on the enclosure. The Public Utility will procure, install, test, and own all revenue metering equipment. Standalone revenue metering will be located on the high side of generator step up transformer. The metering will be bi-directional to measure KWH and KVARH quantities for both generation received and retail load delivered. There will be no additional station service metering for supplying generation load. The metering generation and billing data will be remotely interrogated via the Public Utility's MV90 data acquisition system.

Station Service/Construction Power

The Applicant must arrange distribution voltage retail meter service for electricity consumed by the project when not generating. Temporary construction power metering shall conform to the Six State Electric Service Requirements manual. Applicant must call the PCCC Solution Center 1-800-640-2212 to arrange this service. Approval for back feed is contingent upon obtaining station service

7.0 Cost Estimate

The following estimate represents only scopes of work that will be performed by the Public Utility. Costs for any work being performed by the Applicant are not included.

OCS001 POI Recloser *Primary metering, develop relay settings*	$36,000
Distribution Circuit *Underground extension*	$42,000
Communications *Install communications equipment and fiber*	$143,000
Prineville Substation *Install communications, protection equipment and voltage transformer*	$146,000
Total	**$367,000**

*Any distribution line modifications identified in this report will require a field visit analysis in order to obtain a more thorough understanding of the specific requirements. The estimate provided above for this work could change substantially based on the results of this analysis. Until this field analysis is performed the Public Utility must develop the Project schedule using conservative assumptions. The Applicant may request that the Public Utility perform this field analysis, at the Applicant's expense, prior to the execution of an Interconnection Agreement in order to obtain more cost and schedule certainty.

This estimate is as accurate as possibly given the level of detailed study that has been completed to date and approximates the costs incurred by Public Utility to interconnect this Community Solar Project to Public Utility's electrical distribution or transmission system. An estimate, based on finer detail, will be calculated during the Facilities Study. The Applicant will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by the Applicant.

8.0 Schedule

The Public Utility estimates it will require approximately 12-15 months to design, procure and construct the facilities described in this report following the execution of an Interconnection Agreement. The schedule will be further developed and optimized during the Facilities Study.

Please note, the time required to perform the scope of work identified in this report does not support the Applicant's requested commercial operation date of November 1, 2020.

9.0 Participation by Affected Systems

Public Utility has identified the following Affected Systems: None

10.0 APPENDICES

Appendix 1: Higher Priority Requests
Appendix 2: Informational Network Resource Interconnection Service Assessment
Appendix 3: Property Requirements

10.1 Appendix 1: Higher Priority Requests in the Local Area of the Requested POI

All active higher-priority requests for transmission service and/or generator interconnection service (including requests in the traditional interconnection queue and other requests in the Community Solar queue) in the local area of the requested POI will be considered in this study and are identified below. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.

Generation Interconnection/Community Solar Queue Requests considered:

Queue #	Size (MW)
443	34.56
621	55
731	55
734	62.3
739	58.5
824	40
850	60.75
1093	600
1161	40
1162	80
1163	40
1164	80
1165	600

10.2 Appendix 2: Informational Network Resource Interconnection Service Assessment

The study results described above reflect an energy resource interconnection service ("ERIS") evaluation, modified in the CSP program rules to examine only generation and load conditions local to the requested CSP project's interconnection point (sometimes referred to as the "zoomed in view"). The "zoomed in view" functions to: (1) study the project's proposed interconnection without considering certain existing or higher-queued requests outside of the local area; and (2) to inform whether the CSP facility must cap its project to mitigate, although not eliminate, the risk of potential deliverability-related network upgrades to accommodate the proposed CSP generator.

By contrast, the following informational section provides a network resource interconnection service ("NRIS") evaluation performed with traditional assumptions, i.e., not modified to examine only local generation and load conditions, but rather one that assumes that all existing interconnections, higher-queued requests for interconnection service (in both the traditional and CSP queue), and generators with executed contracts beyond the local area are in-service. Depending on the severity of the conditions created when absorbing additional generation (capped or not capped) in that broader, "zoomed out" area, the local area-focused generator size cap developed in the "zoomed in" examination may not be sufficient to mitigate the need for deliverability-related network upgrades. Regardless of this report's informational NRIS results, the deliverability-related network upgrades ultimately necessary to accommodate the proposed CSP generator will depend on conditions present when the future transmission service study is performed, as well as whether network upgrade alternatives are available at that time.

There are currently a significant number of higher-queued requests seeking interconnection in the Prineville area where the CSP generator proposes to interconnect. These interconnection studies must be completed before the transmission provider can determine what upgrades and associated cost estimates may be required for the aggregate of generation in the local area to be delivered to the aggregate of load on the transmission provider's transmission system (the NRIS study scope).

10.3 Appendix 2: Property Requirements

Requirements for rights of way easements

Any Rights of Way easements will be acquired by the Applicant in the Public Utility's name for the construction, reconstruction, operation, maintenance, repair, replacement and removal of Public Utility's Interconnection Facilities that will be owned and operated by PacifiCorp. Applicant will acquire all necessary permits for the project and will obtain rights of way easements for the project on Public Utility's easement form.

Real Property Requirements for Point of Interconnection Substation (if required)

Real property for a point of interconnection substation will be acquired by an Applicant to accommodate the Applicant's project. The real property must be acceptable to Public Utility. Applicant will acquire fee ownership for interconnection substation unless Public Utility determines that other than fee ownership is acceptable; however, the form and instrument of such rights will be at Public Utility's sole discretion. Any land rights that Applicant is planning to retain as part of a fee property conveyance will be identified in advance to Public Utility and are subject to the Public Utility's approval.

The Applicant must obtain all permits required by all relevant jurisdictions for the planned use including but not limited to conditional use permits, Certificates of Public Convenience and Necessity, California Environmental Quality Act, as well as all construction permits for the project.

Applicant will not be reimbursed through network upgrades for more than the market value of the property.

As a minimum, real property must be environmentally, physically, and operationally acceptable to Public Utility. The real property shall be a permitted or able to be permitted use in all zoning districts. The Applicant shall provide Public Utility with a title report and shall transfer property without any material defects of title or other encumbrances that are not acceptable to Public Utility. Property lines shall be surveyed and show all encumbrances, encroachments, and roads.

Examples of potentially unacceptable environmental, physical, or operational conditions could include but are not limited to:

- Environmental: known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; violation of building, health, safety, environmental, fire, land use, zoning or other such regulation; violation of ordinances or statutes of any governmental entities having jurisdiction over the property; underground or above ground storage tanks in area; known remediation sites on property; ongoing mitigation activities or monitoring activities; asbestos; lead-based paint, etc. A phase I environmental study is required for land being acquired in fee by the Public Utility unless waived by Public Utility.

- Physical: inadequate site drainage; proximity to flood zone; erosion issues; wetland overlays; threatened and endangered species; archeological or culturally sensitive areas; inadequate sub-surface elements, etc. Public Utility may require Applicant to procure various studies and surveys as determined necessary by Public Utility.

- Operational: inadequate access for Public Utility's equipment and vehicles; existing structures on land that require removal prior to building of substation; ongoing maintenance for landscaping or extensive landscape requirements; ongoing homeowner's or other requirements or restrictions (e.g., Covenants, Codes and Restrictions, deed restrictions, etc.) on property which are not acceptable to the Public Utility.